U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

233 Peachtree Street Ste. 600
Atlanta, GA 30303

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

May 22, 2007

Mr. Samuel L. Dozier
Vice President and Commercial Field Operations
Carolina Gas Transmission (CGT)
105 New Way Road
Columbia, South Carolina 29224-2407

CPF 2-2007-1009M

Dear Mr. Dozier:

On October 2-5 and October 23-26, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected Carolina Gas Transmission (CGT) procedures for gas integrity management program in Columbia, South Carolina.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within CGT plans or procedures, as described below:

1. **§192.911(a)**

   § 192.911(a) An identification of all high consequence areas, in accordance with § 192.905.

   § 192.905 How does an operator identify a high consequence area?

   (a) *General.* To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition

in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area.

(b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites. (i) Visible marking *(e.g.*, a sign); or (ii) The site is licensed or registered by a Federal, State, or local government agency; or (iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) *Newly identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in § 192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

§ 192.903 What definitions apply to this subpart?

***High consequence area* means an area established by one of the methods described in paragraphs (1) or (2) as follows:**

(1) An area defined as—(i) A Class 3 location under § 192.5; or (ii) A Class 4 location under § 192.5; or (iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or (iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or (ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. *(See* Figure E.I.A. in appendix E.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle *(i.e.*, the prorated number of buildings intended for human occupancy is equal to [20 x (660 feet [or 200 meters]/ potential impact radius in feet [or meters]) 2]).

***Identified site* means each of the following areas: (a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or (b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or (c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.**

***Potential impact circle* is a circle of radius equal to the potential impact radius (PIR).**

***Potential impact radius* (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d 2)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of**

the pipeline in inches. Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S–2001 (Supplement to ASME B31.8; ibr, see § 192.7) to calculate the impact radius formula. *Remediation* is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

- **Item 1A: § 192.905(a) and § 192.903(2), (3), and (4)**

There are no detailed procedures describing a repeatable process by which HCA maps are produced. Flow charts are being used that do not adequately address the process used to produce the maps. For example, the flow charts do not describe who is to perform specific tasks and how they are to document the output of those tasks. In addition, there is inadequate guidance for application of PIRs as they relate to identified sites. For example, no direction is provided that describes where a PIR is to be located in relation to a school with a playground.

- **Item 1B: § 192.905(b) and § 192.903(4)**

There is no documentation of the basis for inclusion or exclusion of identified sites. Additionally, no instructions are provided regarding how to provide this documentation.

- **Item 1C: § 192.905(b)**

There is a lack of instruction provided to emergency responders to ensure that they provide consistent and quality feedback during events designed to obtain this information. There was no documentation available to substantiate HCA identification updates.

2. §192.911(b)

§192.911(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior

assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years; (ii) MAOP increases; or (iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8 S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

§ 192.919 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (See §192.917)

(c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

§ 192.921 How is the baseline assessment to be conducted?

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with § 192.917(c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

§ 192.933 What actions must be taken to address integrity issues?

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this

section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in § 192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under § 192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in § 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

- **Item 2A: § 192.917 (e)(3) and (4)**

  CGT program and procedure requirements are inadequate to track MOP and MAOP changes to ensure that stable long seam threats do not become unstable for both covered and non-covered segments.

- **Item 2B: § 192.919(c), § 192.921(d), § 192.933(b), and § 192.937(a)**

  CGT does not have program requirements to ensure that the date for completion of field activities for an assessment is recorded so that the timeframe for evaluating anomalies and reassessment date(s) can be accurately determined.

3. §192.911(c)

§192.911(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (ibr, see § 192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking; (2) Static or resident threats, such as fabrication or construction defects; (3) Time independent threats such as third party damage and outside force damage; and (4) Human error.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§ 192.935) for the covered segment.

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

- **Item 3A: § 192.917(a)**

CGT's IMP includes a statement (in Section 4.4) that threat interaction will be considered, but includes no process for implementation. The Kiefner model currently used by CGT, does not address threat interaction.

- **Item 3B: § 192.917(a)**

  CGT has concluded, without an adequate documented basis, that three threats – stress corrosion cracking, internal corrosion, and human error – are not threats of concern throughout their system.

- **Item 3C: § 192.917(e)(1)**

  There is no procedure to assure that data on encroachments and foreign line crossings are integrated with ILI or ECDA results. This data integration process is required by 192.917(e)(1) for addressing the threat of third-party damage.

- **Item 3D: § 192.917(c)**

  CGT has insufficient description in its program to demonstrate that risk assessment is being used to address the objectives listed in ASME/ANSI B31.8S, other than risk ranking of HCA segments.

- **Item 3E: § 192.917(c)**

  There are no provisions in the plan or procedures to assure that risks are re-evaluated on a periodic basis or that the risk analysis process is integrated into other processes.

- **Item 3F: § 192.917(c)**

  There is no detailed process to assure validation of risk results against company/industry experience.

4. **§192.911(d)**

   §192.911(d) A direct assessment plan, if applicable, meeting the requirements of §§ 192.923, and depending on the threat assessed, of 192.925, 192.927, or 192.929.

   §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

   (b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (ibr, see § 192.7), section 6.4, and in NACE RP 0502–2002 (ibr, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage,

the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by § 192.917(e)(1).

(1) *Pre-assessment.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 3, the plan's procedures for pre-assessment must include— (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment.

(2) *Indirect Examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 4, the plan's procedures for indirect examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and (iv) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP0502–2002), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502–2002).

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in § 192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917...For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

- **Item 4A: § 192.925(b)(3)(ii)(B)**

  There is no documented process for performing root cause analysis when the operator uncovers problems for which ECDA is not well suited.

- **Item 4B: § 192.925(b), § 192.917(a) and (c), and § 192.937(a) and (b)**

  CGT has no documented process to continuously assess for SCC during the direct examination step of the ECDA process. Further, there is no evidence that SCC assessments have been completed for examinations performed to date.

- **Item 4C: § 192.925(b)(3)(i)**

  CGT could not identify provisions in its ECDA Plan or more restrictive criteria it applied when conducting the ECDA direct examination step for the first time on a covered segment.

5. §192.911(e)

§192.911(e) Provisions meeting the requirements of § 192.933 for remediating conditions found during an integrity assessment.

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements...* An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment...

...A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (ibr, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation.*—

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2 /3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

- **Item 5A: § 192.933(c)**

The CGT IMP does not have a requirement to develop a schedule that prioritizes evaluation and remediation of anomalous conditions.

- **Item 5B: § 192.933(d)(3)**

  There are no detailed procedures to describe the process for recording anomalies that are classified as "monitored conditions" and monitoring them during subsequent risk assessments and reassessments.

- **Item 5C: § 192.933(c)**

  There are no detailed procedures describing a repeatable process by which technical justifications are produced when anomaly evaluation timeframes cannot be met.

- **Item 5D: § 192.933(c)**

  The CGT remediation schedule does not provide the criteria in Section 192.933 of the Rule or in ASME B31.8S which is the basis for remediation of the respective anomalies.

- **Item 5F: § 192.933(a)**

  There is insufficient evidence in the CGT remediation records to demonstrate that an anomaly is unlikely to threaten the integrity of the pipeline before the next scheduled reassessment. The operator relies upon contractor's reports to provide this evidence, however the contractor's reports do not provide sufficient details for these conclusions. For example, safe pressure calculations need to be documented to demonstrate the basis of safety until reassessments are performed.

6. **§192.911(h)**

   §192.911(h) Provisions meeting the requirements of § 192.935 for adding preventive and mitigative measures to protect the high consequence area.

   § 192.935 What additional preventive and mitigative measures must an operator take?

   (a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. *(See* § 192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (ibr, *see* § 192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures

include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in § 192.933, the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

- **Item 6A: § 192.935(a)**

  The CGT IMP does not include an evaluation of threats, a spectrum of preventive and mitigative (P&M) alternatives, and the potential impact on the identified risks for HCA segments.

- **Item 6B: § 192.917(e)(5)**

  There is a lack of program requirements to ensure that identified corrosion issues that meet the "immediate" classification are evaluated for pipeline segments outside of HCAs.

7. **§192.911(k)**

§192.911(k) A management of change process as outlined in ASME/ANSI B31.8S, Section 11.

§192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework *(see* § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The

initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, *see* § 192.7) for more detailed information on the listed element.)

- **Item 7A: § 192.911(k)**

  The criteria used to determine when an MOC form is used to track physical changes to the pipeline are inadequate. Physical changes are being made to the pipelines that are not being tracked using the MOC process.

- **Item 7B: § 192.911(k)**

  The MOC process does not provide sufficient procedures to describe how a change identifies affected documentation and how the change is communicated to affected parties.

- **Item 7C: § 192.911(k)**

  The MOC process does not have provisions to ensure that integrity management system changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program.

8. §192.911(l)

§192.911(l) A quality assurance process as outlined in ASME/ANSI B31.8S, Section 12.

§192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework *(see* § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, *see* § 192.7) for more detailed information on the listed element.)

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?

(a) ***Supervisory personnel.*** **The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program**

must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person— (1) Who conducts an integrity assessment allowed under this subpart; or (2) Who reviews and analyzes the results from an integrity assessment and evaluation; or (3) Who makes decisions on actions to be taken based on these assessments.

(c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person— (1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or (2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

§ 192.7 Incorporation by reference.

(a) Any documents or portions thereof incorporated by reference in this part are included in this part as though set out in full. When only a portion of a document is referenced, the remainder is not incorporated in this part.

- **Item 8A: § 192.911(l)**

  CGT extensively uses contracted services to accomplish important aspects of its IMP. In many areas, the Inspection Team noted that CGT relies on its contractors to perform IMP related work without sufficient guidance and quality assurance procedures and processes.

- **Item 8B: § 192.915(a), (b), and (c)**

  CGT has not established qualification requirements for personnel participating in IMP activities, including in-house personnel responsible for evaluating assessment results.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 2-2007-1009M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Linda Daugherty
Director, Southern
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*